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The California Power Crisis

On June 14, 2000, tens of thousands of consumers and businesses in the San Francisco Bay Area were plunged into darkness as California suffered its largest planned blackout since World War II. On that day, as temperatures in San Francisco reached a record 103 degrees, a series of localized, rolling blackouts stalled subway services across the bay and affected at least 97,000 customers served by the investor-owned utility Pacific Gas & Electric (PG&E).[1]

PG&E was directed to take this action by the California Independent System Operator (CAISO), which had been created to run the state's long-distance electricity transmission system as part of the 1998 restructuring of the California electricity industry. The available supply of electricity was low because of the closure of several generating plants for maintenance purposes, and CAISO ordered the blackouts in hopes of avoiding a major statewide, uncontrolled blackout. In fact, high temperatures sent electricity use spiking all across California, leading state power officials to declare a statewide Stage 1 power emergency. However, what appeared to be an unusual event was merely a foreshadowing of things to come.

On June 28, two consecutive days of sizzling heat in the West prompted electricity grid officials to declare a statewide Stage 2 power emergency during the afternoon.[2] CAISO ordered the three big investor-owned utilities (IOUs) to cut electricity to some customers that had signed up for interruptible power in exchange for lower rates. The shortfall in the supply of electricity that necessitated the power emergency was accompanied by sharp rises in the wholesale electricity price. Facing high levels of demand, utilities such as PG&E found themselves paying extraordinarily high prices for electricity on the wholesale markets. During the Stage 2 emergency, electricity prices reached the maximum price cap of $750 per megawatt-hour (MWh) that had been established in 1999 to prevent price gouging. In comparison, the average wholesale price observed during the same hours in 1999 was $50/MWh. In fact, during the week of June 12, the cost of electricity for all users in California was more than $850 million, three times as much as the most expensive week for electricity in 1999.

Utility officials and consumer groups believed that the astronomical prices were a signal that the market had ceased to function properly. In August 2000 a report by the California Public Utility Commission warned of further increases in the cost of power, prompting Governor Gray

[1] *Frontline,* "Blackout: The California Crisis," WGBH/PBS, http://www.pbs.org/wgbh/pages/frontline/shows/blackout/california.

[2] A Stage 2 emergency refers to a situation in which an electricity market's operating reserves are forecast to be less than 5 percent of anticipated electricity demand. Operating reserves are the amount of generating capacity in excess of projected demand that is available on short notice to meet unexpected surges in demand. A Stage 1 emergency refers to a case in which operating reserves are forecast to be between 5 and 7 percent of anticipated demand, while a Stage 3 emergency, the most severe status, refers to a situation in which operating reserves are below 1.5 percent of anticipated demand. Nonemergency operation occurs when operating reserves exceed 7 percent of anticipated demand.

Davis to call for an investigation into "possible price manipulation in the wholesale electricity marketplace." The viability of California's power industry, and of electric utility deregulation itself, was being brought into question.

The Structure of the Electric Power Industry

Electricity is an unusual commodity in that it cannot be stored easily. Hence, the demand for electricity exhibits large variations over time, reflecting the ever-changing power needs of customers. Demand shows seasonal and hourly variations based on temperature and time of day. Peak electricity usage is usually seen in the summer during the middle of the day, when air-conditioning systems and refrigeration units are working hardest. The lowest demand for electricity occurs at night and on weekends, when temperatures are lowest or factories and institutions are closed.

The electric power industry maintains a steady flow of electric power by performing three basic functions: generation, transmission, and distribution of electricity (**Exhibit 1**). *Generation* is the production of electric energy from energy sources. *Transmission* is the delivery of electric energy over high-voltage lines from power plants to distribution areas. *Distribution* is the delivery of electricity to end-use consumers over a local system of low-voltage lines, substations, and transformers.

The electricity industry in the United States has traditionally been composed of two types of firms: utilities and nonutilities. *Utilities* are privately owned companies and public agencies engaged in the generation, transmission, and/or distribution of electric power for public use. Utilities can be investor-owned, state/municipality-owned, federally owned, or cooperatively owned. Under the traditional regulated system, a utility is given a monopoly franchise over a specific geographic area. In return for this franchise, the utility is regulated by state and federal agencies. Traditional vertically integrated utilities usually own generation facilities and control the transmission and distribution networks within their region. In addition, they are responsible for serving the needs of all retail consumers in their territory. *Nonutilities* are privately owned entities that generate power for their own use and/or for sale in the wholesale power market.

Generation

Generation facilities are owned and operated by both utilities and nonutilities. Electric power generators use a variety of methods and energy sources to generate electric energy. Energy sources include combustion of fossil fuels (natural gas, oil, or coal), nuclear fission, kinetic energy (from falling water or wind), and sunlight. These sources are used to run engines, turbines, water wheels, or similar machines that drive an electric generator.

Generating units vary in size. Nuclear and fossil-fuel steam-electric units typically have large capacities, with many over 1,000 megawatts (MW), while hydroelectric generators range from less than 1 MW to thousands of megawatts at some of the large federal dams. Gas turbines, combustion turbines, and combined-cycle units are typically less than 200 MW. Wind and solar plants are relatively small.

The generating units operated by an electric utility also vary by intended usage. There are three types of load requirements that a utility must meet, generally categorized as base,

intermediate, and peak load. A base-load generating plant is used to satisfy the minimum (or base) load of the system and, as a consequence, produces electricity at an essentially constant rate and runs continuously. Base-load units are generally the largest of the three types, but they cannot be brought on line or taken off line quickly. Base-load units also have the lowest operating cost per kilowatt-hour (kWh). Nuclear power plants usually fall into this category. Peak-load generating units can be brought on line quickly and are used to meet requirements during the periods of greatest, or peak, load on the system (such as the demand spikes seen in afternoons during the summer). They are normally smaller, older plants that use gas and combustion turbines. Peak-load generating units tend to have lower levels of efficiency and higher operating costs per kilowatt-hour than base-load units. For example, an older peak-load plant might have a heat rate (a measure of the efficiency with which the generator converts thermal energy into electrical energy) of 13 million BTU/MWh; by contrast, the heat rate for a newer combined-cycle gas-fired turbine used to satisfy base-load demand would be about 6.8 million BTU/MWh.[3]

The types of energy source used for generating electricity vary in the United States by region and are usually dictated by the availability of natural resources. California's tight restrictions on air emissions discourage coal-fired generation. Many California plants use natural gas, which burns more cleanly than coal, for electricity generation. The energy sources available for electricity generation are a factor in the disparity of retail prices across the nation. For example, the Pacific Northwest enjoys among the lowest electricity rates in the country because of the low cost of hydropower, which it can export to states like California in years with good rainfall.

Transmission

Electric power transmission is the transportation of large blocks of power over relatively long distances from a central generating station to main substations close to major demand centers or from one central station to another. The transmission grid consists of high-voltage overhead and underground lines made of conductors like copper or aluminum. Because of resistance in the conductors, some power is lost as dissipated heat during transmission. As a result, electricity markets tend to stay localized, and it is not possible to use excess capacity in one part of the country to relieve a power shortage in a distant state. At the generating station, the voltage of the three-phase alternating current output from the generator is increased to the required transmission voltage by a step-up transformer. The high-voltage alternating current is then transmitted through the grid to the load center, where it is transformed back to the lower voltages required by distribution lines.

In the United States, IOUs own 73 percent of the transmission lines, federally owned utilities own 13 percent, and state, municipal, and cooperative utilities own 14 percent. Not all utilities own transmission lines; in particular, independent power producers do not own transmission lines. Over the years, transmission lines have been organized into three major networks or grids, which also include smaller groupings or power pools. The major networks consist of extra-high-voltage connections between individual utilities designed to permit the transfer of electrical energy from one part of the network to another. These transfers are restricted, on occasion, because of a lack of contractual arrangements or because of inadequate transmission capability. The three networks are the Eastern Interconnect, the Western Interconnect, and the Texas

[3] J. Sweeney, *The California Electricity Crisis* (Stanford, CA: Hoover Institution Press, 2002).

Interconnect. The interconnected utilities within each power grid coordinate operations and buy and sell power among themselves.[4]

Because electric energy is instantaneously generated and consumed, the operation of an electric power system requires a coordinated balancing of generation and consumption of power. Control area operators perform this function, as well as other important tasks, allowing the interconnected electric power systems and their components to operate together both reliably and efficiently. There are approximately 150 control areas in the United States. Most are run by the dominant IOU in a geographic area defined by an interconnected transmission grid and power plant system. This bulk power system enables utilities to engage in wholesale electric power trade. Wholesale trade has historically played an important role, allowing utilities to reduce power costs, increase power supply options, and improve reliability.

Distribution

Distribution is the delivery of electric power from the transmission system to the end-use consumer. The distribution systems begin at the substations, where power transmitted on high-voltage transmission lines is transformed to lower voltages for delivery over low- voltage lines to consumer sites. The system ends at consumers' meters. Distribution is considered a natural monopoly and is likely to remain a regulated function because duplicate systems of lines would be impractical and costly.

Electricity is sold to four classes or sectors of retail consumers—residential, commercial, industrial, and "other." The residential sector includes private households and apartment buildings. The commercial sector includes nonmanufacturing business establishments, such as hotels, motels, restaurants, wholesale businesses, retail stores, and health, social, and educational institutions. The industrial sector includes manufacturing, construction, mining, agriculture, fishing, and forestry establishments. The "other" sector includes public, street and highway lighting, railroads, municipalities, divisions or agencies of state and federal governments under special contracts or agreements, and other utility departments.

History of the U.S. Electric Power Industry[5]

The modern electric utility industry began in the 1880s, evolving from gas and electric carbon-arc commercial and street lighting systems. Thomas Edison's Pearl Street electricity generating station, which opened September 4, 1882, in New York City, set the foundation for the modern electric utility system. It featured reliable central generation, efficient distribution, and a competitive price. By the end of the 1880s, small central stations had spread through many U.S. cities.

At the beginning of the 20th century, vertically integrated electric utilities produced approximately two-fifths of the nation's electricity and many businesses generated their own electricity. As utilities began to install larger and more efficient generators and more transmission lines, the associated increase in convenience and economical service prompted many industrial

[4] Rebecca A. McNerney, "The Changing Structure of the Electric Power Industry 2000: An Update," Chapter 3 (Washington, D.C.: Energy Information Administration, 2000), http://www.eia.doe.gov/cneaf/electricity/chg_stru_update/toc.html.

[5] This section draws from McNerney, "Changing Structure."

consumers to shift to the utilities for their electricity needs. Consumption of electricity skyrocketed along with utilities' share of the nation's generation.

Utilities operated in designated exclusive franchise areas, which in the early years were usually municipalities. Along with the service area designation came the obligation to serve all consumers within that territory. The growth of utility service territories brought state regulation of privately owned electric utilities in the early 1900s. Georgia, New York, and Wisconsin established state public service commissions in 1907, followed shortly by more than 20 other states.

The early structure of the electric utility industry was predicated on the assumption that because the functions of generation, transmission, and distribution involved significant economies of scale, an unregulated electricity market would inevitably become dominated by a single firm. The fear that monopolized markets would lead to undue concentration of economic and political power, coupled with the concern that monopoly pricing distortions would reduce economic efficiency, led states to create a structure of public utility regulation, under which the price of electricity was regulated by a state's public service commission. In addition to protecting consumers against monopoly prices, regulation required utilities to make every effort to provide reliable service to consumers in their market areas. For their part, utilities were promised that they would be allowed to earn a fair rate of return on prudent investments needed to maintain reliable electricity service.

By 1920 rate-based regulation by states had become a standard feature of the electric utility industry. However, another development eventually brought about the involvement of the federal government. During the early 1900s, electric utility holding companies—entities that owned several utilities simultaneously—began to form, and by the 1920s they controlled a substantial share of the industry's assets. Because states could not regulate an interstate holding company, these companies operated outside the existing regulatory framework. After several large holding company systems collapsed during the Great Depression, an investigation by the Federal Trade Commission was ordered, eventually leading to the passage of the Public Utility Holding Company Act of 1935, under which holding companies became regulated by the Securities and Exchange Commission. During this same period, the public became disenchanted with privately owned power and began to support the idea of government ownership of utilities. The U.S. government subsequently became heavily involved in the power industry through the construction of several massive hydroelectric facilities.

For decades, utilities were able to meet the increasing demand for electricity at decreasing prices. Economies of scale were realized through the construction of ever-larger generating plants, and per-unit costs were pushed down even further through technological advances in equipment such as turbines. This trend continued until the late 1960s, when the electric utility industry began to experience increasing unit costs and slower growth. Over a relatively short time, a number of events took place that contributed to a turnabout in the industry. The Northeast blackout of 1965 raised pressing concerns about reliability. The passage of the Clean Air Act of 1970 required utilities to reduce polluting emissions. The oil embargo of 1973–1974 resulted in burdensome increases in fossil-fuel prices. The accident at Three Mile Island in 1979 led to higher costs, regulatory delays, and greater uncertainty in the nuclear industry. And, finally, the inflation of the 1970s and early 1980s caused interest rates to more than triple, significantly increasing the costs of capital of most utilities.

While the industry was attempting to recover from this onslaught of damaging events, Congress designed legislation that would reduce U.S. dependence on foreign oil, develop

renewable and alternative energy sources, sustain economic growth, and encourage the efficient use of fossil fuels. One result was the passage of the Public Utility Regulatory Policies Act of 1978 (PURPA), a law designed to promote the development of small-scale electricity generation based on renewable energy sources, such as solar and wind. PURPA became a catalyst for competition in electricity supply by allowing nonutilities (known as qualifying facilities, or QFs) to make wholesale power sales to IOUs. Utilities initially did not welcome this forced competition, but some soon found that buying generation services from a nonutility had certain advantages over adding to their own capacity, especially because of the increasing uncertainty of recovering capital costs.

The growth of nonutilities was further advanced by the passage of the Energy Policy Act of 1992 (EPACT). EPACT expanded nonutility markets by creating a new category of power producers—exempt wholesale generators (EWG)—that did not sell electricity in the retail market and did not own transmission facilities. Moreover, unlike the nonutilities that qualified under PURPA, EWGs were not regulated and were allowed to charge market-based rates. At the same time, utilities were not required to buy their power.

The growth of EWGs marked another step toward increasing the level of competition in the wholesale electricity market. The wholesale electricity market was supervised by the Federal Energy Regulatory Commission (FERC), which was charged with ensuring that wholesale prices were "just and reasonable." However, in the wake of EPACT, FERC began taking steps to ensure that independent power producers would have open access to the transmission grid so that wholesale markets could operate competitively. In particular, through Orders 888 and 889 in 1996, FERC mandated the wholesale trading of electricity between generators and customers regardless of their location. Prior to passage of PURPA in 1979, the electric power industry had been relatively stable for approximately 45 years. By the early 1990s the industry was in the midst of significant structural change that was moving it closer to a competitive market. An attempt at full industry deregulation was the next logical step, and California was among the first states to take that step.

The Electric Power Industry in California

California covers an area of about 163,707 square miles and is home to more than 34 million people. In 1998 California's gross state product was measured at more than $1.1 trillion, which accounted for almost 13 percent of the U.S. GDP and ranked the state as the sixth largest economy in the world. California had played a significant role in the consistently rapid growth of the U.S. economy in the 1990s, largely because of information technology businesses expanding in the Silicon Valley. The state was one of the leaders of the "New Economy" and was the largest producer of electronic equipment components, computers, advanced instruments, and aerospace equipment. It was also the largest provider of computer services, including software, programming, and the Internet. Biotechnology, with a focus in medical and agricultural applications, was another industry that was expanding rapidly in California. Finally, the entertainment industry, centered in Hollywood, continued to be a significant revenue generator for the state.

Demand

Historically, consumption of electricity on a per capita basis in California had been low relative to other parts of the United States.[6] For example, in 1999 California's per capita usage of electricity was 37 percent below the U.S. average. This was due to a combination of factors: California's temperate climate, the fact that its economic base consisted of industries that were not heavy users of electricity, the aggressiveness with which the state promoted programs fostering energy conservation, and the fact that the price of electricity in California in the 1980s and 1990s was significantly higher than the national average.

Growth in aggregate electricity consumption in California was stimulated in large measure by growth in the state's population. Because California's population grew steadily throughout the 1990s, total electricity consumption grew as well. Between 1990 and 1995, electricity consumption increased by 14.5 percent, an average growth rate of about 2.7 percent per year. From 1999 to 2000, consumption grew even faster, at a rate of about 4 percent. **Exhibit 2**, **Exhibit 3**, and **Exhibit 4** summarize the composition of demand for electricity in California in the 1990s.

Supply

California's electricity supply came from a variety of sources. In the 1990s the state generated about 31 percent of its power from natural gas, 20 percent each from hydroelectric and coal-fired plants, 16 percent from nuclear plants, and the rest from renewable sources (see **Exhibit 5**).

Typically, California obtained about 75 percent of its electricity from in-state sources and imported about 25 percent, with imports coming in equal amounts from the Pacific Northwest and the Pacific Southwest. Flows of imports varied during the year. In the summer, when the weather in California is hot, California imported power from the Pacific Northwest. In the winter, when the weather in the Pacific Northwest was cold, California exported power to the Pacific Northwest. These patterns could be affected by variations in weather conditions. For example, a drought in the Pacific Northwest in 1998 and 1999 reduced available hydroelectric power throughout the region between 1998 and 2000, which in turn reduced the amount of hydroelectric power that California could import from the Pacific Northwest during the months when it was needed.

At the beginning of the 1990s, California's electricity market was characterized by a significant amount of excess generating capacity. A major factor contributing to this situation was the completion of over 7,000 MW of new capacity by small producers using renewable fuel sources.[7] Because this excess capacity was expected to persist, relatively little new generating capacity was added in California after 1990. Between 1990 and 1996 annual retirements of generating plants exceeded annual applications for new capacity, and on balance, California's generating capacity decreased by about 1,400 MW between 1990 and 1997.[8] Applications for

[6] Much of the information in this paragraph and the next two draw from J. Sweeney, *The California Electricity Crisis* (Stanford, CA: Hoover Institution Press, 2002).

[7] P. Joskow, "California's Electricity Crisis," *Oxford Review of Economic Policy* 17, no. 3 (2002): 365–388. Under PURPA, IOUs were required to purchase (under long-term contract) almost all of the electricity generated in these new facilities. The price stipulated under the PURPA rules typically made this purchased electricity very expensive.

[8] Sweeney, *California Electricity Crisis* 101. To put this in perspective, California had approximately 26,000 MW of generating capacity in 1998.

new generating plants increased dramatically after the restructuring legislation was approved in 1996. However, as of 2000, none of the proposed plants had become operational.

IOUs

California's electric power industry was dominated by three major IOUs: Pacific Gas and Electric (PG&E), Southern California Edison (SCE), and San Diego Gas and Electric (SDG&E), together accounting for about 70 percent of the state's power in the 1990s. **Exhibit 6** shows the service areas of all the major utilities. PG&E served a 70,000-square-mile region encompassing 13 million people, running from Redding in the north to Lompoc in the south and including the Bay Area and Silicon Valley.[9] SCE served a 50,000-square-mile territory consisting of 11 million people concentrated in central and southern California excluding Los Angeles. SDG&E provided service to 3 million customers in a region consisting of San Diego and southern Orange County. In addition to the IOUs, California had a number of large municipal utilities, including the Los Angeles Department of Water and Power (LADWP), which served Los Angeles, and the Sacramento Municipal Utility District (SMUD).

Environmental Policy

California's utilities were subject to both federal and state environmental regulations. One policy that had a particularly important impact on utilities in Southern California involved the control of NO_x emissions. Under this program, known as the Regional Clean Air Incentives Market or RECLAIM, plants in the South Coast Air Quality Management District (SCAQMD) were allocated a certain number of permits allowing them to emit NO_x into the air. Plants were required to curtail NO_x emissions in excess of their allocation or purchase additional permits at the going market price from firms that did not need their full allocation. The price of RECLAIM permits became an additional operating cost to generating plants operating within the SCAQMD. The program especially affected older, gas-fired turbines (used primarily to satisfy peak demand) because of the large NO_x emissions coming from these plants. Under the program, the supply of permits was reduced every year, and in 1999 and 2000 permit supply declined sharply. **Exhibit 7** summarizes power plant NO_x emissions, as well as the price of permits between 1998 and 2000.

Restructuring the Electric Power Industry in California[10]

The Road to Restructuring

In 1996 the average price of electricity sold in California was 9.48 cents per kWh, tenth highest among the 50 states and the District of Columbia. The U.S. average price at the time was 6.86 cents per kWh. Concern over high prices led the California Public Utilities Commission (CPUC) in 1992 to initiate a study of California's electric power industry. The study initially

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[9] W. McNamara, *The California Energy Crisis: Lessons for a Deregulating Industry* (Tulsa, OK: Pennwell, 2002).

[10] This section draws from Sweeney, *California Electricity Crisis*; Joskow, "California's Electricity Crisis"; S. Borenstein, J. Bushnell, and F. Wollack, "Diagnosing Market Power in California's Restructured Wholesale Power Market," *American Economic Review* (2002); J. Taylor and P. Van Doren, "California's Electricity Crisis: What's Going On, Who's to Blame, and What to Do," *Policy Analysis* (July 3, 2001): 1–35; and S. Hunt, *Making Competition Work in Electricity* (New York: Wiley, 2002).

resulted in a staff report known as the "Yellow Book," which was followed in April 1994 by the issuance of an order known as the "Blue Book," which set forth a process for achieving a comprehensive restructuring of California's electricity industry. The "Blue Book" proposed a set of reforms that included competitive wholesale power markets, retail choice, and recovery of stranded costs.[11]

With deregulation promising significantly cheaper electricity, the restructuring of California's power market was embraced by a broad coalition of industrial and commercial interest groups, consumer groups, and the electric power industry itself. According to the *Los Angeles Times*, California's three major IOUs spent $4.3 million on lobbyists and $1 million on political campaigns in their efforts to promote deregulation. In December 1995, the CPUC issued its order proposing the restructuring of California's electricity market, and nine months later Governor Pete Wilson signed into law Assembly Bill 1890 (A.B.1890), the legislation that formally mandated the deregulation of California's electric power industry. The new law established a four-year transition period to make the state's electric power industry competitive. Retail competition was scheduled to begin on March 31, 1998, when retail customers would be able choose their electricity provider.

Key Features of A.B.1890

A.B.1890 (and its subsequent implementation by the CPUC) resulted in the following changes in California's electric power industry:

- Retail customer choice was authorized.
- A competition transition charge (CTC) was imposed to facilitate recovery of stranded costs by IOUs.
- Retail rates were frozen at 90 percent of June 1996 levels for residential and small commercial customers and at June 1996 levels for all other retail customers.
- The California independent system operator (CAISO) was created to monitor the transmission system and ensure reliability, as well as open access.
- The IOUs were required to divest a portion of their fossil-fuel generating capacity.
- A legally separate independent power exchange (PX) was created in order to operate a wholesale spot market for power in California.
- The IOUs were restricted from entering into long-term contracts.

RETAIL CHOICE

The new structure gave customers in most existing electric utility service areas the option of purchasing their electricity from a new class of electricity "retailers" known as electricity service providers (ESPs). After March 31, 1998, customers served by SDG&E, PG&E, SCE, PacifiCorp,

[11] "Stranded costs" refer to the investments in generating capacity that were made by regulated utilities in anticipation that these investments would earn a regulated rate of return, but which the firms would be unable to recover in a competitive wholesale power market. Stranded costs would arise if competitive wholesale prices were lower than the cost per MWh of producing in a plant. The debate about who would bear the losses associated with stranded costs—and in particular whether formerly regulated utilities would be permitted to recover them (e.g., through extra charges to consumers)—was an important part of debates over electricity deregulation in the United States in the 1990s.

Sierra Pacific Power, or Bear Valley Electric were no longer restricted to purchasing electricity from these local utilities; instead, they could now compare deals and pick the one that best met their needs. Though all consumers retained the default option to purchase their power from their local utility, it was widely anticipated that many retail customers would eventually switch to an ESP during the four-year transition period.

COMPETITION TRANSITION CHARGE

To allow the IOUs to recover stranded costs, retail purchasers of electricity would be assessed a competition transition charge (CTC). The CTC would, in effect, be a tax on electricity purchases that retail customers would have to pay, whether they purchased their electricity from their default service provider or from an ESP.[12] A.B.1890 enabled the IOUs to issue tax-exempt bonds through the California Infrastructure and Economic Development Bank whose interest would, in effect, be financed through the proceeds the IOUs received from the CTC. By allowing utilities to refinance a portion of their generating assets using high-grade debt, these bonds enabled utilities to reduce their cost of capital and lower their taxes.

ELECTRIC RATE FREEZE AND REDUCTIONS IN RATES

The imposition of the CTC essentially meant that California's consumers were being asked to pay for the recovery of the IOUs' stranded costs. To make this politically palatable, A.B.1890 mandated that an IOU's rates for agricultural, industrial, and large commercial customers would be frozen at June 1996 levels, while rates for residential and small commercial customers would be frozen at a rate 10 percent below June 1996 levels. The rate freeze was accomplished by making the CTC vary inversely with the wholesale price of electricity. As a result, the retail price of electricity paid by an end consumer—which equaled the wholesale price of electricity *plus* the CTC—remained fixed. (For retail consumers, the sum of the wholesale price and the CTC was frozen at about 6¢ per kWh.[13]) At the time of deregulation, it was widely assumed that competition would drive the wholesale price of electricity downward. If this happened, the difference between the *retail* electricity price paid by an end consumer and the *wholesale* price paid by the IOU to procure the electricity (a difference that, by construction, was equal to the CTC and was informally known as "head room") would serve as a mechanism allowing an IOU to recoup its stranded costs. The retail price freeze would remain in effect until March 31, 2002, unless utilities were able to recover their stranded costs before that time.[14] At that point, the CTC would be removed, and the price of electricity paid by a retail customer would equal the wholesale price of electricity.

CAISO

As explained above, CAISO was a nonprofit organization created to operate the network of high-voltage transmission lines owned by California's three IOUs. It was also given responsibility for running load-balancing and congestion management services. CAISO received FERC approval in October 1997 and became operational on March 31, 1998.

[12] To understand this charge, keep in mind that when a customer purchases electricity from a local utility, it pays a "bundled rate" that includes the price of the electricity itself (the energy price) plus a price for the delivery of electricity over the local network to the customer's premises (the distribution charge). Even if a customer bought its electricity from an ESP (paying an energy price to the ESP, rather than the local utility), it would still pay a distribution charge to the utility. The CTC was, in effect, to be added to the distribution charge.

[13] On top of the effective retail price of the electricity itself, a consumer's electricity bill also included charges for the distribution and transmission of electricity. These latter rates continued to be regulated by the state of California.

[14] If during this period a customer switched to an ESP and later switched back to its default service provider, the customer would continue to purchase electricity at the capped rate.

At the onset of deregulation, the IOUs owned and operated a large portion of the state's transmission system. To increase reliability and provide new power producers equal opportunity, IOUs were required to transfer operational control of these facilities to CAISO. This move was designed to ensure that owners of the transmission system could not favor their own generation facilities over competing generators in providing transmission access or block access by others. Local distribution lines would continue to be operated by the existing electric utilities. The local utilities would be required to give customers direct access to any seller of electricity operating in their area. In addition, CAISO was given responsibility for maintaining overall electricity system reliability by maintaining reserve generators in the event that a generator failed to deliver the required amount of power. The major responsibility of CAISO was to ensure fair and impartial access to the high-voltage transmission system for all generators while maintaining reliable operation. The transmission system was to continue to be owned by the investor-owned utilities. Generators who shipped electricity through the system would pay a fee to cover the system costs and ensure reliability.

DIVESTITURE

In order to ensure the creation of a workably competitive market, the three large IOUs—PG&E, SCE, and SDG&E—were required to divest 50 percent of their fossil-fuel generating capacity, and were provided with strong financial incentives to divest the rest. As **Exhibit 8** shows, over 20,000 MW of in-state fossil-fuel units had been divested by the IOUs by the year 2000. The buyers of these assets included Duke Energy Corporation, Southern Company Energy Marketing (now known as Mirant), Dynergy, Reliant Energy Services, and AES.[15] The three IOUs retained their nuclear power plants and hydroelectric plants, and they were allowed to continue to purchase power under their existing long-term contracts.

POWER EXCHANGE AND WHOLESALE MARKET OPERATIONS

The Power Exchange (PX), a nonprofit corporation regulated by FERC, also became operational on March 31, 1998. The PX, which conducted day-ahead and hour-ahead markets for electricity for each hour in the day, was intended to be the state's primary institution for the sale and purchase of electric power at the wholesale level. For both its day-ahead and hour-ahead markets, the PX operated according to a double-auction format. It solicited offers at which electricity buyers were willing to purchase electricity and bids at which generators and electricity marketers were willing to sell electricity, and it established a market-clearing price based on those offers and bids. In particular, offers to purchase particular amounts of electricity (e.g., in a particular hour) would be ranked from highest offer price to lowest offer price (i.e., in buyers' "merit order") to form a demand curve, while bids to sell particular quantities of electricity would be ranked from lowest bid price to highest bid price (i.e., in sellers' "merit order") to form a supply curve. The intersection of the demand curve and the supply curve determined the market-clearing price in that period. Buyers whose offers exceeded the market-clearing price bought electricity at that price, while sellers whose bids were less than the market-clearing price sold electricity at the market-clearing price.

Independent power producers, municipalities, energy marketers, irrigation districts, and out-of-state producers were permitted to buy and sell power on the PX, but they were not required to do so. By contrast, California's three large IOUs—PG&E, SCE, and SDG&E—were required to meet all of the electricity demand arising from their default retail service obligations by

[15] Subsequent to its purchase of California generating assets, AES entered into a contract with energy marketer and pipeline company Williams to dispatch and market the electricity produced in these plants.

purchasing power on the PX. In addition, they were required to bid into the PX all of the energy produced by their remaining generating units and by long-term purchase contracts that were in existence prior to restructuring.[16]

In addition to the PX, CAISO operated a real-time "imbalance energy" market that was responsible for matching the total supply and total demand of electricity at every instant in time so that the transmission grid could operate properly. In this market, additional electricity could be acquired if actual demand exceeded supply, while generators could sell surplus electricity if demand was less than supply. Like the PX markets, the CAISO real-time market was conducted according to a double-auction format. Because firms faced no penalties for deviating from the schedules established in the PX day-ahead and hour-ahead markets, CAISO's imbalance market was very active and in effect became the spot market for electricity in California, with the PX markets operating essentially as short-term forward markets.

Both the PX market and the CAISO real-time market employed price caps that placed an upper limit on wholesale prices. The price cap in the PX market was $2,500/MWh. The cap in the CAISO real-time market was, at various times, $250/MWh, $500/MWh, or $750/MWh.

LONG-TERM CONTRACTS

As noted above, California's IOUs were required to purchase all of their electricity through the PX. Following the passage of A.B.1890, the CPUC severely restricted the ability of the IOUs to enter into long-term contracts to purchase electricity. Policy makers were concerned that if long-term contracts were allowed, the IOUs might make long-term supply deals with the companies that had purchased their generators, the anticipation of which could distort the prices at which such assets were sold. This, in turn, could complicate the assessment of stranded costs that would need to be recovered. Further, some policy makers feared that such deals might allow the IOUs to continue to control the generating capacity that they had been required to divest themselves of. Starting in 1999, the IOUs petitioned the CPUC to allow them to enter into long-term contracts to purchase power. However, through 2000 all such requests were denied.

California's Experience: 1998–1999

California's deregulated marketplace began operating in April 1998. By and large, during 1998 and 1999 it appeared to be functioning quite competitively. The wholesale prices that prevailed during those years (about $30/MWh on average) were below recent historical norms. (See **Exhibit 9** for monthly average prices in the PX day-ahead market during 1998 and 1999.) The divestiture of utility assets proceeded smoothly, and the three large IOUs were generating profits that served to defray their stranded costs. In fact, by July 1999 SDG&E had fully recovered its stranded costs, and at that point retail rates in San Diego were unfrozen.

The principle surprise was that retail choice did not take hold very quickly. By early 2000, despite significant advertising campaigns by power marketers and the creation of new market players called aggregators who could group the small users to benefit from purchasing economies, only about 1 percent of California's residential customers had switched from their default IOU to an ESP. In fact, Enron's ESP subsidiary eventually abandoned attempts to enlist

[16] In practice, the IOUs' nuclear capacity, as well as electricity purchased under long-term contracts from QFs, was classified as "must-take" capacity. Electricity supplied by "must-take" capacity was required to be offered for sale into the PX at a zero price. Under this system, the IOUs, in effect, had to "buy back" their self-generated electricity at the prevailing wholesale price.

residential customers because consumers were so unreceptive to switching.[17] **Exhibit 10** shows the percentage of California's total electricity demand that was served by ESPs in September 2000.

The California Power Crisis: 2000–2001

The Crisis Begins

Starting as early as May 2000, the wholesale electricity price in California began to increase. Before long, prices began reaching the CAISO wholesale price cap of $750/ MWh. (This cap represented the maximum allowable price in the wholesale market. The $750/MWh cap remained in effect until July 2000 when it was lowered to $500/MWh. In August 2000, the cap was again lowered, this time to $250/MWh.) Wholesale prices during the summer averaged between $100 and $200/MWh each month, and the wholesale prices that prevailed in June and July 2000 were 270 percent higher than the prices that prevailed during those same months in 1999. (See **Exhibit 11** for average monthly prices in the PX day-ahead market during 2000 and 2001, and **Exhibit 12** for daily variations in wholesale prices in 1999 and 2000.) Because retail rates continued to be frozen for customers in PG&E's and SCE's service areas, the higher wholesale prices were not passed through to end users. By contrast, retail rates in SDG&E's service area had been unfrozen since July 1999, so consumers in the San Diego area began experiencing large increases in retail rates.

California had maintained a 10 percent reserve margin for the summer's expected peak electric demand, assuming all plants and transmission lines were working perfectly. However, since plants and transmission lines often run at less than their theoretical capacity, the state's reserve power margin had already fallen below 5 percent a half-dozen times on hot days by the beginning of August 2000, prompting CAISO to declare Stage 2 alerts.

The Crisis Escalates

The extremely high wholesale prices during the summer were widely ascribed to the high demand brought about by the hot summer and the supply shortages caused by power plant outages. (See **Exhibit 13** for hourly demand for electricity in California in 2000.) These price spikes were considered by many to be a transient phenomenon that would disappear as the demand for electricity declined during the winter months. However, to the surprise of most observers, prices remained high during the fall and winter months, often reaching the price cap of $250/MWh.

On December 7, 2000, California faced an unprecedented energy alert. Suffering from idled power plants and independent generators who had become skittish about selling electricity to the state's increasingly cash-strapped IOUs, CAISO declared the first statewide Stage 3 power alert, meaning power reserves had dipped below 3 percent. With California facing its tightest supply of electric power ever, U.S. Energy Secretary Bill Richardson issued a rare emergency order for out-of-state power suppliers to sell electricity to California at "just and reasonable" rates.

[17] J. Taylor and P. Van Doren, "California's Electricity Crisis: What's Going On, Who's to Blame, and What to Do," *Policy Analysis* (July 3, 2001).

During December, wholesale prices on the PX cleared at an average of $385/MWh, over 12 times higher than the average market-clearing price of $30/MWh in December 1999. On December 15, FERC issued an order encouraging California's utilities to enter into long-term contracts with power generators in order to avoid paying the high wholesale prices on the PX. The order approved a flexible rate cap plan of $150/MWh, but allowed the power generators to charge more if they could prove a higher price was warranted. But California consumer groups and Governor Gray Davis, who had asked the FERC to implement rate caps on wholesale electric power, criticized the plan on the grounds that it would allow generators to charge more than was warranted.

Unable to pass escalating wholesale prices along to retail consumers, California's two largest IOUs saw their losses continue to mount. On January 16, 2001, SCE announced it would not be able to pay $596 million it owed creditors because it had run out of cash. PG&E also threatened to default on bill payments, and by late January 2001 the credit ratings of both utilities were downgraded to low junk status.

By early 2001, the frequency and severity of blackouts had also increased. From January 15 through February 13, a Stage 3 emergency was in effect every day, and rolling blackouts were ordered on January 17 and January 18. With millions of households and businesses vulnerable to interruptions in electricity service, frustrations mounted at the obvious melt-down of California's deregulated electricity market. Some observers suggested that California's experience reflected the operation of a competitive electricity market buffeted by an unusual set of circumstances. In particular, they argued that the escalation in wholesale prices could be traced to a combination of high natural gas prices, high demand for electricity, and reduced imports. (**Exhibit 14** provides information on average natural gas prices in California and across the United States for 1999–2001; **Exhibit 15** shows average temperatures in San Francisco and San Jose in 1999 and 2000; **Exhibit 16** provides information on monthly demand in 1999 and 2000; **Exhibit 17** provides data on imports of electricity in 1999 and 2000.) By contrast, other observers alleged that the wholesale market was being manipulated by independent generators and power marketers to take advantage of tight supply-demand conditions. (See **Exhibit 18** for information on capacity withheld from the market during 1999 and 2000.) Still others believed that California's restructuring had been poorly designed, and the problems experienced in 2000 and 2001 would continue to recur unless key design flaws were fixed.

As the spring of 2001 approached, the CPUC and FERC had many difficult decisions ahead of them. It was unclear if the modifications instituted would be effective or if a fundamental overhaul of the system was needed. With the possibility of severe power shortages, continued blackouts, and the bankruptcy of California's largest utilities, the fate of the state's booming economy hung in the balance. California needed a feasible solution to this complex problem. The challenge lay in identifying the fundamental sources of the crisis in the first place.

Kellogg School of Management

NORTHWESTERN UNIVERSITY

Exhibit 1: Components of the Utility Industry

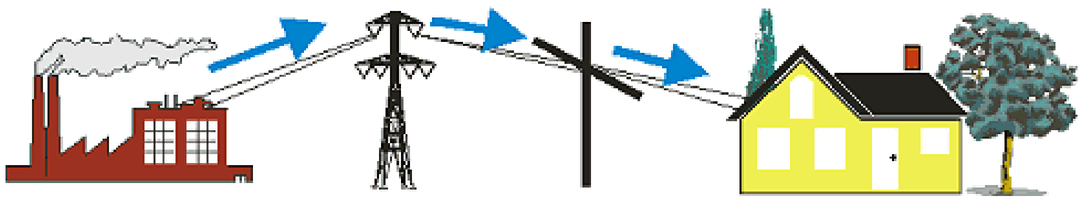


Exhibit 2: Utility Sales, Revenue, and Customers by Type of Utility in California, 1999

	Investor-Owned	Public	Federal	Coop.	Total
Number of utilities	6	34	2	4	46
Number of retail customers	10,040,653	2,845,132	108	13,487	12,899,380
Retail sales (thousand MWh)	153,524	51,924	6,284	249	211,981
Percentage of retail sales	72.4	24.5	3	0.1	100
Revenue from retail sales (million dollars)	14,999	4,672	101	20	19,792
Percentage of revenue	75.8	23.6	0.5	0.1	100
Revenue per kilowatt-hour (cents)	9.77	9	1.61	7.89	9.34

Source: Energy Information Administration/State Electricity Profiles—California, http://www.eia.doe.gov/cneaf/electricity/st_profiles/california/ca.html.

Exhibit 3: Utility Retail Sales in California (in thousands of MWh)

	1990	1994	1999
Residential	66,575	68,866	74,490
Commercial	79,691	76,925	78,154
Industrial	55,892	59,864	49,595
Other	8,935	8,030	9,743
Total	211,093	213,684	211,981

Source: Energy Information Administration/State Electricity Profiles—California, http://www.eia.doe.gov/cneaf/electricity/st_profiles/california/ca.html.

Exhibit 4: Utility Retail Revenues in California, 1999 (in millions of dollars)

	1990	1994	1999
Residential	8,050	8,587	7,978
Commercial	9,133	9,148	7,856
Industrial	4,931	4,633	3,552
Other	490	438	406
Total	22,603	22,806	19,792

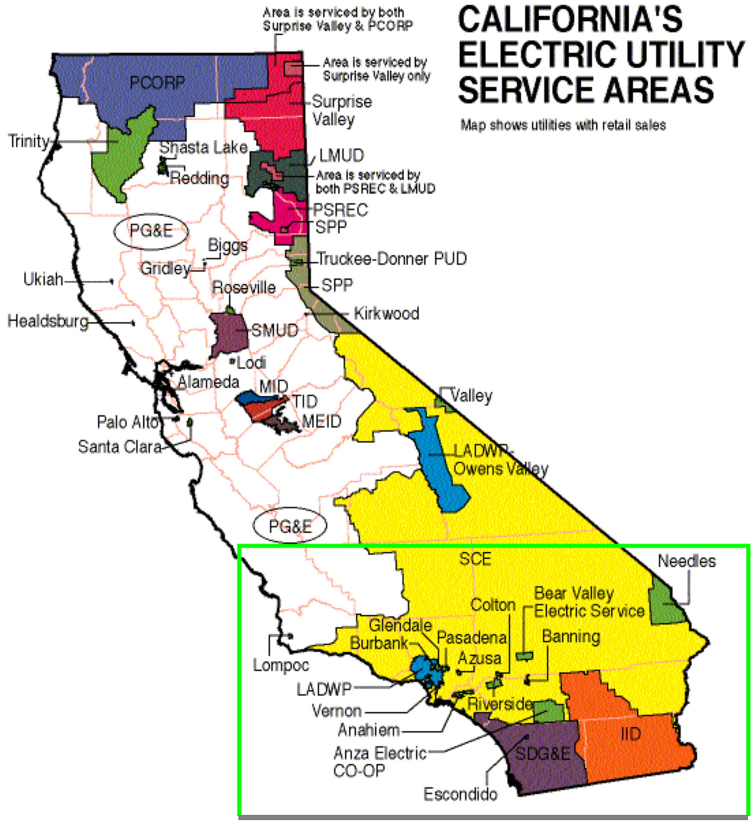
Source: Energy Information Administration/State Electricity Profiles—California, http://www.eia.doe.gov/cneaf/electricity/st_profiles/california/ca.html.

Exhibit 5: Electric Power Industry Generation of Electricity in California by Energy Source

	1990	1994	1999	2000
Total Generation (GWh)	252,355	256,719	275,803	280,496
Hydroelectric	26,092	25,626	41,627	42,053
Nuclear	36,586	38,828	40,419	43,533
Coal	21,402	25,095	36,327	36,804
Oil	4,449	1,954	55	449
Gas	76,082	95,025	84,703	106,878
Geothermal	16,038	15,573	13,251	13,456
Organic waste	6,644	7,173	5,663	6,086
Wind	2,418	3,293	3,433	3,604
Solar	681	798	838	860
Other	4	0	0	0
Imports	61,959	43,354	49,487	26,774

Source: California Energy Commission, http://www.energy.ca.gov/electricity.

Exhibit 6: Electric Utility Districts in California, 1996



Abbreviations	
CSC:	Santa Clara Electric Dept.
IID:	Imperial Irrigation District
LADWP:	Los Angeles Dept. of Water and Power
LMUD:	Lassen Municipal Utility District
MEID:	Merced Irrigation District
PCORP:	PacifiCorp
PG&E:	Pacific Gas & Electric
PSREC:	Plumas-Sierra Rural Electric Cooperative
SCE:	Southern California Edison
SDG&E:	San Diego Gas & Electric
SMUD:	Sacramento Municipal Utility District
SPP:	Sierra-Pacific Power
TID:	Turlock Irrigation District

Source: California Electricity Commission, http://www.energy.ca.gov/maps/map_electric_utility.html.

Exhibit 7: NO_x Emissions and RECLAIM Permit Prices

Plant Type	Approximate NO_x Emissions in Generating Electricity
Typical base-load generator	0.10 lb/MWh
Older gas-fired turbines (primarily peak-load)	4.00 lb/MWh

Year	Market Price of NO_x Permits
1998	\$0.75 – \$1.50/lb
1999	\$2.15/lb
2000	\$22.50/lb

Source: J. Sweeney, *The California Electricity Crisis* (Stanford, CA: Hoover Institution Press, 2002), 122–123.

Exhibit 8: Divestiture of IOU-Generating Assets in California

Power Plant	Seller	Purchaser	Capacity (MWh)	Book Value (\$ in millions)	Sale Price (\$ in millions)
Morro Bay, Moss Landing, Oakland	PG&E	Duke Energy Corp.	2,881	390.2	501.0
Contra Costa, Pittsburg, Potero	PG&E	Southern Energy	3,166	318.3	801.0
Geysers (Sonoma & Lake Counties)	PG&E	Calpine Corp.	1,353	273.1	212.8
Alamitos, Huntington Beach, Redondo Beach	SCE	AES Corp.	4,706	224.1	781.0
Cool Water, Etiwanda, Ellwood, Mandalay, Ormond Beach	SCE	Houston Industries	4,019	288.3	277.0
El Segundo, Long Beach	SCE	NRG Energy and Desctec	1,583	168.8	116.6
San Bernadino, Highgrove	SCE	Thermo Ecotek	300	(4.3)	9.5
Encina, Kearny	SDG&E	NRG Energy and Dynergy	1,347	94.8	365.0
South Bay	SDG&E	San Diego Unified Port District	833	64.4	110.0

Source: Table 2.2 in J. Sweeney, *The California Electricity Crisis* (Stanford, CA: Hoover Institution Press, 2002), 63.

Exhibit 9: California PX Day-Ahead Prices, Month by Month, 1998–1999 ($/MWh, weighted average across hours and days)

Month	1998	1999
January		21.6
February		19.6
March		24.0
April	23.3	24.7
May	12.5	24.7
June	13.3	25.8
July	35.6	31.5
August	43.4	34.7
September	37.0	35.2
October	27.3	49.0
November	26.5	38.3
December	30.0	30.2
Average	30.0	30.0

Source: Table 1 in P. Joskow, "California's Electricity Crisis," *Oxford Review of Economic Policy* 17, no. 3 (2002): 375.

Exhibit 10: Proportion of California's Total Electricity Demand Served by ESPs, September 2000

	% of Total Demand
Residential	2.0
Commercial < 20 kW	3.8
Commercial 20–55 kW	12.8
Industrial > 500 kW	27.4
Total	12.0

Source: Table 2 in P. Joskow, "California's Electricity Crisis," *Oxford Review of Economic Policy* 17, no. 3 (2002): 376.

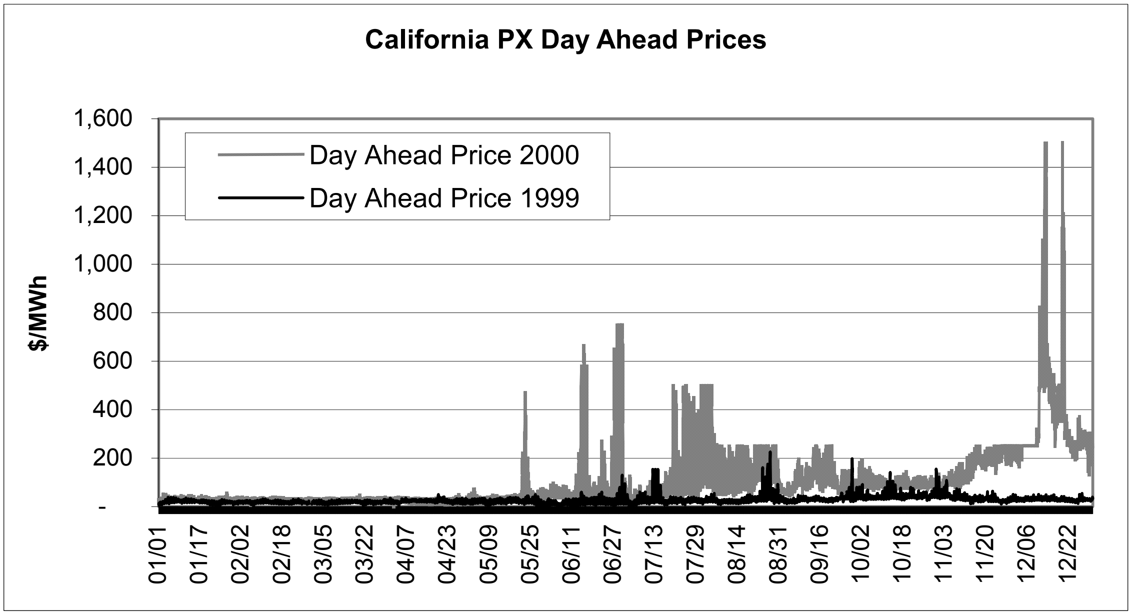
Exhibit 11: California PX Day-Ahead Prices, Month by Month, 2000–2001 ($/MWh, weighted average across hours and days)

Month	2000	2001[a]
January	31.8	260.2
February	18.8	363.0
March	29.3	313.5
April	27.4	370.0
May	50.4	274.7
June	132.4	
July	115.3	
August	175.2	
September	119.6	
October	103.2	
November	179.4	
December	385.6	
Average	115.0	

Source: Table 1 in P. Joskow, "California's Electricity Crisis," *Oxford Review of Economic Policy* 17, no. 3 (2002): 375.

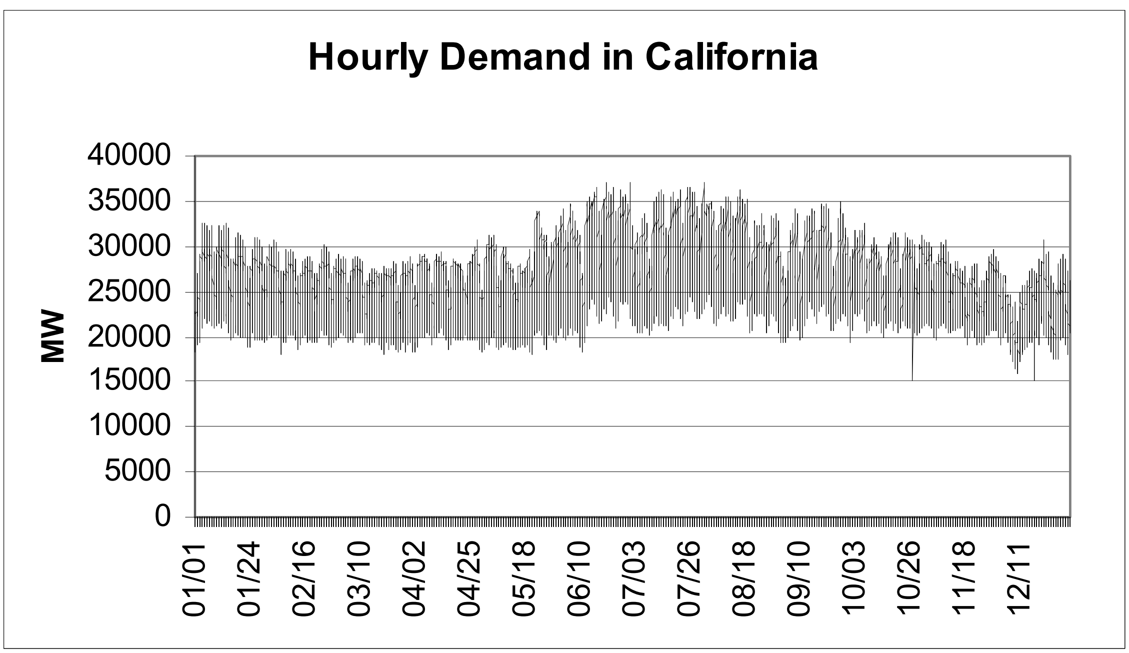
[a] February–May are CAISO market prices.

Exhibit 12: Comparison of Wholesale Prices of Electricity in California, 1999 vs. 2000



Source: PX Unconstrained Market Clearing Prices and Quantities in Day-Ahead Market, http://www.ucei.berkeley.edu/ucei/datamine/px_umcp.html.

Exhibit 13: Demand for Electricity in California, 2000



Source: CAISO data, http://www.ucei.berkeley.edu/ucei/datamine/iso_eng_system.htm.

Exhibit 14: Natural Gas Prices in California and United States, 1999–2001 ($/Mcf)[a]

Month	1999	2000	2001
		California	
January	2.21	2.59	12.64
February	2.20	2.88	9.42
March	2.06	2.90	8.36
April	2.15	3.40	7.52
May	2.70	3.44	7.32
June	2.60	4.42	8.08
July	2.61	4.47	2.92
August	2.82	4.11	2.80
September	3.02	4.98	2.71
October	3.44	5.17	2.38
November	3.27	5.09	3.15
December	2.65	7.30	2.80
		U.S. Average	
January	2.85	3.27	8.91
February	2.92	3.48	7.08
March	2.77	3.54	6.10
April	2.88	3.72	6.30
May	3.25	4.15	5.77
June	3.12	5.19	5.38
July	3.11	5.20	4.03
August	3.39	4.63	4.32
September	3.59	5.21	3.66
October	3.21	5.66	3.37
November	3.71	5.20	4.02
December	3.19	6.64	3.90

Source: U.S. Energy Information Administration, http://www.eia.doe.gov

[a] Mcf = 1000 cubic feet. There are 1.031 million BTU per Mcf. To convert gas prices to $ per million BTU, multiply the above prices by 1/1.031 = 0.96.

Exhibit 15: Comparison of Maximum Temperatures in San Francisco and San Jose, 1999 vs. 2000

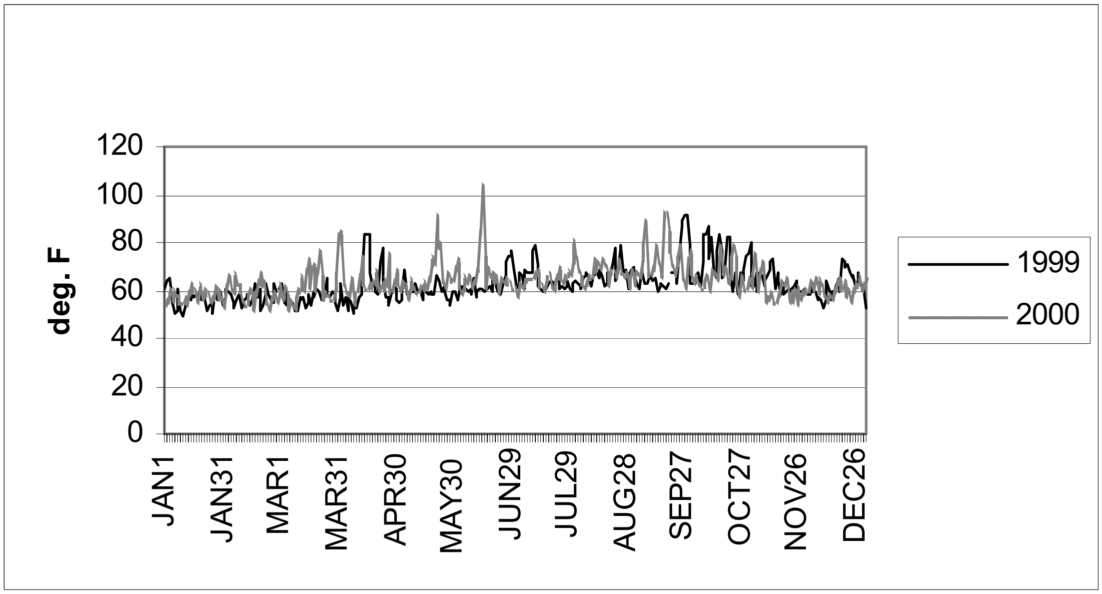


Exhibit 16: Average Hourly Electricity Demand in California, 1999–2000 (MW)

Month	1999	2000
January	24,013	25,516
February	24,194	25,585
March	24,469	25,523
April	24,166	25,329
May	24,271	26,883
June	26,609	29,981
July	28,878	29,501
August	29,055	31,104
September	27,930	28,639
October	26,822	26,125
November	25,144	25,912
December	25,919	26,901

Source: Table 3 in P. Joskow, "California's Electricity Crisis," *Oxford Review of Economic Policy* 17, no. 3 (2002): 379.

Exhibit 17: Average Hourly Net Imports of Electricity into California, 1999–2000 (MW)

	1999	2000
May	6,127	4,481
June	5,740	3,367
July	6,551	2,183
August	6,358	1,578
September	6,814	2,962
October	5,641	4,621
November	6,741	4,040
December	7,680	3,211

Source: Table 4 in P. Joskow, "California's Electricity Crisis," *Oxford Review of Economic Policy* 17, no. 3 (2002): 379.

Exhibit 18: Comparison of Average Capacity Offline in California, 1999 vs. 2000 (MW)

	1999	2000
January	3,068	2,423
February	5,096	3,243
March	5,740	3,389
April	5,739	3,329
May	3,032	4,012
June	1,216	2,683
July	963	2,233
August	878	2,434
September	1,195	3,621
October	1,761	7,633
November	2,988	10,343
December	2,569	8,988

Source: California Energy Commission, http://www.energy.ca.gov/electricity.